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Via Email and UPS Overnight

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue
Bismarck, ND 58501-1947

Re: EPA's Comments on the North Dakota Department of Health's April 2010 Draft BACT Determination for NO_x for the Milton R. Young Station

Dear Mr. O'Clair:

This letter transmits the United States Environmental Protection Agency's (EPA's) comments on the North Dakota Department of Health's (NDDH's) April 2010, Draft Best Available Control Technology (BACT) Determination for Nitrogen Oxides (NO_x) for Milton R. Young Station (MRYS), Units 1 and 2 (Draft BACT Determination).

The Draft BACT Determination concludes that low-dust and tail end Selective Catalytic Reduction (SCR) are not cost effective NO_x controls at MRYS. The Draft BACT Determination found that low-dust SCR (LDSCR) would be more cost effective than tail-end SCR (TESCR), and evaluated the cost effectiveness of LDSCR based upon NDDH's conclusion that the average cost effectiveness for LDSCR is $4,201 per ton for Unit 1 and $4,822 per ton for Unit 2.[1] NDDH's Draft BACT Determination also concludes that LDSCR was not cost effective because of the incremental costs of these controls.

The Draft BACT Determination is not supported by the record and is not reasonable in light of applicable statutory and regulatory provisions for two reasons. First, the Draft BACT Determination relied upon unreasonable assumptions and factors not authorized by law to determine the cost effectiveness of SCR at MRYS. This resulted in a significant overestimate of

1. Since NDDH found that LDSCR was more cost effective than TESCR, these comments are focused on LDCSR, but most of the comments also apply to TESCR.

the cost of these controls. Second, even NDDH's unreasonably inflated cost estimates are on the same order as costs previously borne by other sources and must be considered cost effective.

I. SCR is Cost Effective Based upon NDDH's Inflated Cost Estimates

The Consent Decree that EPA and NDDH entered into with Minnkota requires NDDH to conduct its BACT analysis in accordance with the applicable federal and state statutes, and the provisions of Chapter B of EPA's "New Source Review Workshop Manual---Prevention of Significant Deterioration and Nonattainment Area Permitting," (October 1990) (NSR Manual).[2] The NSR Manual is used nationwide in PSD permitting decisions and provides that, "if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT."[3] The NSR Manual further provides that "cost estimates used in BACT are typically accurate to ± 20 to 30 percent. Therefore, control cost options which are within ± 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options."[4]

According to the NSR Manual, the economic impacts component of a BACT analysis may include an examination of both the average cost effectiveness and the incremental cost effectiveness of a control option.[5] The Manual defines the "average cost effectiveness" as the "total annualized costs of control divided by annual emission reductions, or the difference between the baseline emission rate and the controlled emission rate. . ."[6]

NDDH's Draft BACT Determination failed to conduct an adequate comparison of the average cost effectiveness of SCR at MRYS with other sources. NDDH only reviewed the cost effectiveness of a small select group of facilities with SCRs in nearby states, ignoring the costs borne by facilities that installed NO_x controls throughout the country. The Clean Air Act, the PSD regulations, and the NSR Manual do not allow a permitting authority to restrict its comparative review to a subset of the whole of the sources that have undergone BACT review for NO_x. This review should have been nationwide, and the dollars per ton removed of NO_x can be compared to sources undergoing PSD review across the country. Although a permitting authority may consider unique circumstances relating to the location of a facility in determining the total costs of a BACT control technology at that facility, it may not ignore the cost effectiveness determinations from other parts of the country and choose to allow

2 *See* http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf.
3. *See* NSR Manual at B.44.
4. *Id.*
5. *See* NSR Manual at B.41.
6. *Id.* at B.36.

facilities to avoid the installation of BACT level controls by setting unreasonable low cost effectiveness thresholds.

The Draft BACT Determination is also deficient because it compared the calculated cost effectiveness of LDSCR at MRYS with the average of the costs of controls from the facilities within the small group selected by NDDH, instead of comparing the MRYS costs with individual costs at the other facilities. NDDH's comparison of the cost effectiveness of LDSCR at the MRYS with the average costs of a small group of facilities is inconsistent with the NSR Manual and frustrates the technology-forcing function of the BACT process because it ignores the higher costs that other sources had to bear to install the same controls. Since the NSR program is designed to maximize the use of improved technologies and requires controls that will achieve the maximum reductions, the BACT analysis cannot just compare the cost effectiveness of proposed controls with the average costs borne by other sources, but should favor consideration of the highest control costs borne by other sources. The requirement in the Clean Air Act is for the "Best" available controls, not the "Average" available controls.

Even the select group of control costs that NDDH used in the Draft BACT Determination demonstrates that the cost effectiveness of LDSCR at MRYS was on the same order as the costs borne by other facilities. NDDH's Draft BACT determination concludes that the cost effectiveness for NO_x controls at Wygen 3 was $4,037 per ton. This is within 4% of NDDH's conclusions regarding the cost effectiveness of LDSCR at Unit 1 ($4,201 per ton) and within 19 % of NDDH's conclusions regarding the cost effectiveness of LDSCR at Unit 2 ($4,822 per ton). NDDH also compares the cost effectiveness of LDSCR at MRYS with the BART cost analysis conducted for a number of units. Although EPA is not clear why NDDH relied upon these cost analyses, the cost of installing LDSCR at MRYS would also be on the same order as the cost of installing SCR at these units, even based upon NDDH's inflated cost estimates.

NDDH also had information in the record relating to the cost effectiveness of at least two units that were on the same order as the cost effectiveness as LDSCR at MRYS, but did not include any discussion of these units in the Draft BACT Determination. On May 4, 2010, in response to a request from EPA, NDDH sent EPA "two files which contain excerpts from the BACT analyses we reviewed."[7] These files contained a Permit Application Analysis from the Wyoming Department of Environmental Quality (WDEQ) with information regarding the cost estimates for Wygen 2. This document shows that the cost effectiveness of installing SCR at Wygen 2 to meet a rate of 0.06 lbs/MMBtu was $4,156 per ton. WDEQ stated "[t]he BACT analysis indicates that 0.06 lb/MMBtu is technically feasible and the Division considers the total and incremental cost effectiveness to be reasonable."[8] The files also contained documents from the NDDH record with information from the RACT BACT LAER Clearinghouse relating to

7. *See* Enclosure 1.
8. *See* Enclosures 1 & 2.

Wisconsin Public Service Company's Weston 4 coal fired power plant. This information indicates that $6,116 per ton for installing SCR was considered cost effective by Wisconsin.[9]

Since the NSR Manual provides that "control cost options which are within ± 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options," even the data from NDDH's record indicates that the cost of LDSCRs at MRYS is on the same order as the cost effectiveness of other sources and should, therefore, be presumed to be cost effective.

The Draft BACT Determination states that the cost effectiveness of some of the facilities that it used for its comparison can be misleading because Minnkota used the highest removal efficiency of any analysis reviewed. As NDDH points out, the NSR Manual does state that an unrealistically low assessment of the emission reduction potential of a certain technology could result in inflated cost effectiveness figures. The NSR Manual explains that the emissions reductions must be considered reasonable, and supportable assumptions regarding control efficiencies should be made. Since the emissions reductions that were used in the cost estimates in this case were proposed by Minnkota and are consistent with current industry trends, it is reasonable to expect the LDSCRs at MRYS to achieve this removal efficiency. Furthermore, the discrepancy in assumed control efficiency can likely be attributed to MRYS's high baseline emission rate and thus, a higher potential for emission reduction. For example, the baseline emission rate noted in the NDDH determination for Sherco #2 is 0.20 lb/MMBtu compared to 0.85 lb/MMBtu for MRYS Unit 1. As such, the SCR technology can be expected to have a higher percent removal at MRYS Unit 1 compared to Sherco #2 when the baseline emissions at MRYS are over four times higher than the baseline emissions at Sherco #2.

After EPA received NDDH's Draft BACT Determination, it conducted a review of the cost effectiveness of NO_x controls at other facilities and a review of relevant literature and policy documents related to the cost effectiveness of NO_x controls. The determination of BACT is based on the pollutant that triggered PSD, in this case NO_x, and therefore the cost effectiveness (in dollars per ton removed) of any BACT control for NO_x for any type of source can be compared to the cost effectiveness of any other source of NO_x.. The results of this review, which are described below, make it clear that LDSCR is cost effective at MRYS, even based upon the inflated cost estimates used by NDDH:

- In 2001, EPA issued guidance related to presumptive BACT for NO_x at refineries being modified to meet EPA's low sulfur gasoline regulation. This guidance used a cost effectiveness threshold of $10,000 per ton of NO_x controlled in 2001 dollars.[10]

9. *See* Enclosure 1.

- The cost effectiveness threshold used for NO_x reduction by several California air pollution control districts are substantially more than the threshold in this EPA guidance document, ranging from $9,700 to $24,500 per ton.[11]
- Nebraska, Utah, Alabama, and Oklahoma have each stated that costs below $5,000 per ton will be presumed to be cost effective.[12]
- EPA Region 5 sent letters to Ohio and Indiana finding controls that were more expensive than LDSCR at MRYS to be cost effective.[13]
- EPA Region 4 sent letters to Alabama finding controls that were more expensive than LDSCR at MRYS to be cost effective.[14]
- A paper presented at the June 2002 Air and Waste Management meeting reported the results of a survey of the threshold for economic feasibility in the BACT determinations and in the LAER determinations separately by state. This survey reported that Connecticut's BACT Determination average cost per ton was $9,000, Arkansas's was $5,108, and Michigan's was $22,000.[15]

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10. *See* Memorandum from John S. Seitz, Director, OAQPS, to Air Division Directors regarding BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects., *available at* http://www.epa.gov/ttn/caaa/t1/memoranda/bactguid.pdf. *See also*, Delaware Air Regulation Development Committee Meeting #2 Minutes, April 19, 2006, *available at* http://www.regulations.gov/search/Regs/home.html#documentDetail?R=09000064807b7424.

11. *See* San Joaquin Valley Unified Air Pollution Control District, Final Staff Report: Update to BACT Cost Effectiveness Thresholds, May 14, 2008 *available at.* http://www.valleyair.org/busind/pto/bact/May%202008%20BACT%20cost%20effectiveness%20threshold%20update%20staff%20report.pdf, *See also* San Joaquin Valley Unified Air Pollution Control District, Draft BACT Control Technology Policy, March 1, 2010, (proposing to change BACT threshold for NOx form $9,700 to $24,500), *available at* http://71.6.68.10/Workshops/postings/2010/03-01-10/Draft%20BACT%20policy%20-%20Mar%202010%20_2_.pdf.

12. *See* Nebraska Department of Environmental Quality BACT Guidance Document, *available at* http://www.deq.state.ne.us/Publica.nsf/c4afc76e4e077e11862568770059b73f/0949822f884b8ce1862573bd007da0e9?OpenDocument, Utah Department of Environmental Quality, Best Available Control Technology Summary, *available at* http://www.airquality.utah.gov/Permits/FORMS/Form01b.pdf, and Energy and Environmental Analysis, Inc's Regulatory Requirements Database for Small Electricity, *available at* http://www.eea-inc.com/rrdb/DGRegProject/States/AL.html, and http://www.eea-inc.com/rrdb/DGRegProject/States/OK.html.

13. These letters are set forth in Enclosure 3. Note that the cost effectiveness outlined in these letters should be adjusted to 2006 dollars for an accurate comparison to LDSCR at MRYS.

14. These letters are set forth in Enclosure 4. Note that the cost effectiveness outlined in these letters should be adjusted to 2006 dollars for an accurate comparison to LDSCR at MRYS.

15. *See* Enclosure 5. "Comparison of the Most Recent BACT/LAER Determinations for Combustion Turbines by State Air Pollution Control Agencies, Paper #: 42752, AWMA Meeting June 2002. Enclosure 4 also contains an email from the state of Florida explaining that the reported results for Florida in this survey reflect the average actual cost effectiveness during the relevant time period, and does not reflect Florida's view of the cost effectiveness thresholds.

- In 2001, EPA and the States of Arkansas, Nebraska, and Utah entered into a Consent Decree with NuCor that stated that pollution control projects that are demonstrated to cost $5,000 or less per ton reduced are presumptively economically feasible.[16]
- Wyoming Department of Environmental Quality's Permit Application Analysis for Mountain Cement Company's Laramie Cement Plant considered an average cost effectiveness of $4,540 per ton to be cost effective.[17]
- A review of information in the RACT BACT LAER Clearinghouse revealed at least fourteen facilities in twelve states that identified NO_x controls that were more expensive than NDDH's estimates of the cost effectiveness of LDSCR at MRYS.[18]
- The Environmental Appeals Board noted in a 1989 decision that the range of costs normally expended for NO_x removal was $3,000 - 6,500/ton. After adjusting for inflation, these costs are at least on the order of NDDH's cost estimates for LDSCR at MRYS. *See* In the Matter of Columbia Gulf Transmission Company, PSD Appeal No. 88-11 (EAB, Jun 21, 1989) at 825.

If a permitting authority compares the cost effectiveness of a BACT determination today with the cost effectiveness of a BACT determination from past years, it must consider the effects of inflation to properly compare the older project to the one under consideration.

As more fully set forth in EPA's previous comments to NDDH, a number of national rulemakings, including the Clean Air Interstate Rule (CAIR), the Best Available Retrofit Technology (BART) Guidelines, and revisions to the New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units all support the position that SCR is not only technically feasible, but also cost effective for controlling NO_x emissions from North Dakota Lignite.

NDDH's Draft BACT Determination concluded that "[t]he expected cost effectiveness [of LDSCR at MRYS] is higher than other plants where SCR has been applied as BACT."[19] The information set forth above clearly demonstrates that even NDDH's inflated cost estimates are on the same order as costs previously borne by other sources and must be considered cost effective.

NDDH's Draft BACT Determination also considered the incremental costs of LDSCR. The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option. The incremental cost

16. *See* Enclosure 6.
17. *See* Enclosure 7.
18. *See* Enclosure 8.
19. *See* NDDH's Draft BACT Determination at p. 12.

effectiveness is then determined by the difference in total annual costs between two contiguous options divided by the difference in emissions reduction. [20]

In *In re General Motors*, 10 E.A.D. 360, (EAB 2002), the Environmental Appeals Board explained the interplay between average and incremental cost. The Board explained that "the Draft NSR Manual, while allowing for both average and incremental cost effectiveness analysis, places primary stress on the average cost measure. See Draft NSR Manual at B.31 (BACT cost effectiveness analysis turns on the average and, where appropriate, incremental cost effectiveness of the control alternative). Moreover, the Draft Manual cautions that:

> [U]ndue focus on incremental cost-effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the cost-effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs. Id. at B.46. This caution against allowing incremental cost calculations to unjustifiably inflate the cost component of the BACT analysis is in keeping with the objective of the CAA that less effective control technologies be employed only when the source-specific economic impacts or other costs prevent a source from using a more effective technology. See generally Senate Debate on S. 252 (June 8, 1977) reprinted in 3 Senate Committee on Environmental and Public Works, A Legislative History of the Clean Air Act Amendments of 1977, p. 729 (statement of Sen. Edmund Muskie, sponsor of S. 252, stating that BACT, while allowing for flexibility based upon source specific factors, is intended to "maximize the use of improved technology")." Id. at 370-378

Although it is not clear from the Draft BACT Determination how much emphasis NDDH placed on the incremental cost effectiveness of LDSCR at MRYS, it is clear that the incremental cost effectiveness of LDSCR compared to SNCR is not a valid basis for rejecting SCR as BACT. Since the average cost effectiveness of LDSCR at MRYS is well within the range of acceptable BACT costs, it would be inconsistent with the NSR Manual to place undue focus upon the incremental cost effectiveness of these controls to reject LDSCR as BACT.

In its analysis, NDDH lists several projects where a permitting agency rejected a more stringent control option and the corresponding incremental cost effectiveness for the rejected technology. It is not possible to tell from the Draft BACT Determination how much weight the permitting agency gave, if any, to incremental cost effectiveness in the selection of the less-stringent option. As noted above, incremental cost effectiveness is not the primary criteria used in a BACT determination. As such, it should not be assumed that the permitting agency gave significant weight to incremental costs in the determinations cited by NDDH. Moreover, considering the relatively small amount of emphasis that can be given to incremental cost effectiveness, making any sort of direct comparison of the incremental cost effectiveness from one project to the next is difficult at best.

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20. *See* NSR Manual at B.43.

The only three projects where NDDH states that the more stringent control technology was rejected "based on" incremental cost are the Dry Fork Plant near Gillette, Wyoming (SCR at 0.043 lb/MMBtu), the ADM facility in Columbus, Nebraska (SNCR achieving 0.05 lb/MMBtu), and Deseret Power in Uintah County, Utah (limestone injection and a wet scrubber). The other projects listed by NDDH simply state the incremental cost effectiveness for the rejected control option. NDDH does not state that incremental cost effectiveness was a significant factor in the determination.

EPA examined the three BACT determinations that NDDH stated were based on excessive incremental costs. The Draft BACT Determination stated "[t]he State of Wyoming rejected an SCR operating at $0.043 lb/10^6$ Btu at the Dry Fork Plant based on an incremental cost of $10,300/ton."[21] This statement is incorrect. As more fully set forth above, NDDH sent EPA excerpts of the documents that it relied upon to compare the cost effectiveness of LDSCR at MRYS with other facilities. One of these documents included excerpts from the WDEQ Permit Application Analysis for the Dry Fork coal fired power plant. EPA obtained a copy of the complete document. Page 7 of this document, which was not included in the excerpts from NDDH, directly contradicts NDDH's conclusion regarding incremental cost effectiveness, and states "[t]he Division considers the incremental cost effectiveness of $10,303/ton reasonable for an additional 117 tpy emission reduction but does not consider an incremental cost effectiveness of $23,744/ton reasonable for an additional 50 tpy emission reduction."[22]

EPA also reviewed the details of Nebraska's BACT determination for the ADM facility.[23] While Nebraska states "$5600 per of additional NO_x emissions reduction is excessive," it is clear that incremental cost was not the only reason Nebraska eliminated SNCR at a rate of 0.05 lb/MMBtu and made a BACT determination of SNCR at a rate of 0.07 lb/MMBtu. In fact, Nebraska's analysis states that 0.05 lb/MMBtu for SNCR is "not considered technically feasible due to the increased opacity and fabric filter plugging from high levels ammonia salt formation." Since the State of Nebraska concluded that it was not technically feasible for the facility to meet a 0.05 lb/MMBtu rate, NDDH cannot conclude that Nebraska rejected this control option based upon the incremental cost effectiveness. Nebraska also stated that the reasons why SNCR at 0.05 lb/MMBtu was rejected as BACT include "opacity increases by 10 percentage points or more, ammonia slip level increases above 10 ppm increases condensable PM emissions, and the increases in fine particulate matter and ammonia emissions make the proposed BACT limit for particulate matter unattainable." Even if the incremental cost was given significant emphasis by Nebraska, as noted above, $5,600 per ton is even less than what has been considered to be cost effective for average costs. Therefore, Nebraska's citation

21. NDDH's Draft BACT Determination at p. 12.
22. *See* Enclosure 9. Although it is not clear where NDDH obtained these excerpts or how it reached a conclusion that is directly contradicted by the plain language of the full document, we expect that NDDH may have obtained these excerpts from EPA's administrative record in the Deseret Bonanza matter.
23. *See* Nebraska PSD Permit for ADM's Columbus, Nebraska facility, p. 148, *available at* http://www.epa.gov/region07/air/nsr/archives/2006/finalpermits/adm_columbus_final_psd_permit.pdf.

of $5,600 per ton being excessive for incremental cost effectiveness should be considered an outlier and reliance on this determination as a basis for incremental cost effectiveness is unwarranted.

NDDH's reliance upon Region 8's incremental cost analysis regarding the Deseret Bonanza Waste Coal-Fired Unit (WCFU) is misplaced for several reasons. First, the incremental cost analysis that NDDH refers to relates to SO_2, and not NO_x. Second, EPA Region 8's elimination of wet scrubbing with limestone injection in favor of dry scrubbing plus limestone injection for SO_2 BACT at WCFU was not entirely "based on an incremental cost of $10,540/ton," as stated by NDDH. EPA Region 8 noted in its Final Statement of Basis for the permit that, in addition to the relatively higher H_2SO_4 formation that results from a wet scrubber, "[w]et FGD systems also require significantly more water than the dry FGD system. This is an especially important consideration for Deseret's project, which will be located in an arid region of Utah."[24] The issue of water use in wet versus dry scrubbing systems is generally recognized in SO_2 BACT determinations in Region 8 states. While there have been some projects that have proposed wet scrubbers for larger pulverized-coal units, there have also been pulverized-coal projects permitted with dry scrubbing as BACT controls for SO_2. The issue of water use is often cited as why dry scrubbing is selected over wet scrubbing. This is significant in that for pulverized-coal facilities, there is no limestone injection upstream of the control device removing substantial amounts of SO_2, as there are with circulating fluidized bed (CFB) boilers, such as that being permitted for the Bonanza WCFU project. Since there is no limestone injection upstream of a scrubbing system (wet or dry) for a pulverized-coal unit, the selection of dry scrubbing, with lower SO_2 removal efficiencies compared to wet scrubbing, becomes even more critical because the difference in overall tons of SO_2 removed would be greater for pulverized coal units compared to CFB units. Nonetheless, there have been BACT determinations in the West for pulverized coal fired units that have concluded dry scrubbing is BACT for SO_2.

Dry scrubbing with limestone was the most stringent BACT control option found by Region 8 to have been selected by permitting agencies for CFB boilers at the time the Bonanza WCFU permit was issued.[25] In fact, Region 8 stated in its Final Statement of Basis for the permit that it was "not aware of any CFB boilers equipped with a wet scrubbing system." However, Region 8 did find wet scrubbing to be a technically feasible control option for the Bonanza WCFU. Limestone injection to the CFB boiler with 85% control was assumed in the overall control efficiency of all add-on control options presented.

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24. *See* Final Statement of Basis for Deseret Power Electric Cooperative Bonanza Power Plant, p. 96, *available at* http://www.epa.gov/region8/air/pdf/FinalStatementOfBasis.pdf.

25. *See* Final Statement of Basis for Permit No. PSD-OU-0002-04.00 pages 97 – 100. Permits with BACT determinations issued to AES Puerto Rico and Nevco Energy issued 8/10/04 and 10/12/04 respectively. Permit applications had also been submitted for CFB units proposing dry scrubbing (in addition to limestone injection) for Red Trail Energy LLC – Richardton Ethanol Plant, MDU Co. - Gascoyne Generating Station and Great Northern Power Development – South Heart.

Finally, the overall control efficiencies listed in the Final Statement of Basis for wet scrubbing and dry scrubbing (in combination with limestone injection) are 99.1% and 98.8%, respectively. The difference in overall SO_2 reduction between wet scrubbing and dry scrubbing (in combination with limestone injection) was 63 tons per year. In contrast, the incremental NO_x emission reductions between ASOFA plus SCR and ASOFA plus SNCR calculated in the NDDH NO_x BACT Determination are 3,439 tons per year for Unit 1 and 5,490 tons per year for Unit 2. This equates to an incremental difference in NOx emission reductions at MRYS compared to the SO_2 emission reductions at Bonanza WCFU of 55 times more for Unit 1, 87 times for more Unit 2, and 142 times more collectively.

In summary, while it is true that Region 8 did cite "unacceptably high incremental SO_2 removal costs" in its reasoning for selecting dry scrubbing over wet scrubbing in the Bonanza WCFU SO_2 BACT determination, it cannot be said that this decision was "based on" the incremental cost. As described above, there were other important considerations (most notably water conservation in an arid location) that went into this determination. These other considerations were determined by Region 8 to outweigh the additional 63 tons per year reduction that would be achieved by selecting a wet scrubber over a dry scrubber. It should be noted that Region 8's final BACT determination selected the most stringent control technology of any CFB unit permitted at that time with a permitted level of control consistent with the most stringent BACT determinations. As such, the $10,540 ton per year incremental cost cited in this determination should not be viewed as an independent "bright line" value. As noted above, there are many significant differences between the Bonanza WCFU and MRYS projects. Furthermore, as explained below, the non-standard cost methods used in the NDDH Draft BACT Determination undermine the ability to make meaningful comparisons between the incremental costs calculated for MRYS with other similar projects.

II. NDDH's Draft BACT Determination Failed to Follow EPA's NSR Workshop Manual

NDDH was and is required to conduct its BACT determination in accordance with the NSR Manual and OAQPS Control Cost Manual (Control Cost Manual). The Draft BACT Determination did not, however, follow the requirements in these manuals. Rather, it used unauthorized cost methods, included costs for items that are not authorized, and relied upon unreasonably high estimates for a number of costs. As more fully set forth below, conservative revised cost estimates conducted in accordance with the NSR Manual and Control Cost Manual and based upon more realistic estimates for a number of items cause the cost effectiveness of LDSCR at MRYS to drop to approximately $2,000 per ton.

Since the significance of cost effectiveness values is determined by comparing the costs for a given project to costs at other sources, it is critical that permitting authorities throughout the United States follow a standardized approach for determining the cost effectiveness of controls. The NSR Manual explains:

> Consistency in the approach to decision-making is a primary objective of the top-down BACT approach. In order to maintain and improve the consistency of BACT decisions made on the basis of cost and economic considerations, procedures for estimating control equipment costs are based on EPA's OAQPS Control Cost Manual and are set forth in Appendix B of this document. Applicants should closely follow the procedures in the appendix and any deviations should be clearly presented and justified in the documentation of the BACT analysis.[26]

The Control Cost Manual also emphasizes the importance of using a consistent approach to determining the cost effectiveness of controls. The Introduction to the Control Cost Manual explains:

> The objectives of this Manual are two-fold: (1) to provide guidance to industry and regulatory authorities for the development of accurate and consistent costs (capital costs, operating and maintenance expenses, and other costs) for air pollution control devices, and (2) to establish a standardized and peer reviewed costing methodology by which all air pollution control costing analyses can be performed.[27]

A. **Inflated Capital Cost Estimates and Cost Methods**

SCR systems are being successfully applied to virtually every kind of stationary source (utility boilers, incinerators, cement plants, glass plants, etc.) and fuel type (coal, biomass, coke, etc.) worldwide. In meeting these varied and significant challenges for the widespread deployment of SCR technology, system designers must always tailor the specifics of SCR application to the varied conditions at each facility and the most suitable location for installing the system. Although there are admittedly some unique aspects of the MRYS, almost all facilities that have installed SCRs have had unique design challenges.

Capital costs for the installation of SCR on a coal fired electric generating unit are commonly reported on a dollar per kilowatt of capacity basis. Minnkota's BACT analysis, prepared by Burns & McDonnell (B&McD), which was used by NDDH to determine the cost effectiveness of LDSCR, states that the estimated capital cost for LDSCR at MRYS based upon a shared facilities approach was $543/kW for Unit 2 and $525/kW for Unit 1.[28]

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26. *See* NSR Manual, at B-52
27. *See* Control Cost Manual, 2002, Chapter 1, Section 1.1.
28. *See* November 2009 report by Burns & McDonnell, "NO_x Best Available Control Technology Analysis Study – Supplemental Report for the Milton R. Young Station Unit 1, revised February 2010, p. 4-11, and November 2009 report by Burns & McDonnell, "NO_x Best Available Control Technology Analysis Study – Supplemental Report for the Milton R. Young Station Unit 2, p. 4-11.

In its BACT analysis, B&McD stated that a cost range for conventional high-dust SCR was reported as between $55 and $150/kW.[29] On February 16, 2006, PowerGen magazine reported the results of survey of SCR capital costs. The survey was conducted by the Electric Utility Cost Group, and included responses from 72 individual units totaling 41 GW (representing 39% of installed SCR systems in the U.S. by MW at the time of the study). The results of this survey showed that costs were generally reported to be in the $100 to $200/kW (in 2006 dollars) range for the majority of the systems, with only three reported installations exceeding $200/kW.[30] Although some studies have reported slightly higher costs, most have reported results that are generally within this range.[31] Furthermore, two PSD permit applications submitted to NDDH in 2005 and 2006 for CFB utility boilers contemplated SCRs downstream of a dry scrubber and baghouse (TESCR) and included estimated capital costs.[32] The estimated capital costs for these two projects ranged from $117/kW to $132/kW. Since these units were designed to burn North Dakota lignite and are very close in size to MRYS Unit 1, it is unclear why the estimated capital cost for MRYS Unit 1 are about four times higher than what was reported in those permit applications.[33]

The fact that B&McD estimated capital costs for the LDSCRs at MRYS are so much higher than the capital costs at other facilities calls the reliability of these cost estimates into question. The reliability of these estimates becomes more questionable in light of the fact that a number of extremely complicated and challenging SCR installations have had capital costs well below the cost estimates for LDSCR at MRYS. There are at least two cold side SCRs that have recently been installed in the United States that should be considered as a relatively reasonable comparison. In 2007, Washington Group International prepared an "Emission Reduction Study" that evaluated what would be the most cost effective SCR configuration at the WE Energies South Oak Creek Units 5, 6, 7 and 8. The report concluded that retrofitting the units with cold-side LDSCRs was determined to be the least expensive option and predicted capital costs for the SCR systems of $190,500,000 total for all units. This comes out to approximately $168/kW for the SCR equipment alone on the combined 1,135 MW at the facility.[34]

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29. *Id.*

30. *See* M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. http://www.powermag.com/coal/Estimating-SCR-installation-costs_506.html. The reported range of $100 - $221/kW.

31. *See* Enclosure 10. J. Edward Cichanowicz, Current Capital Cost and Cost Effectiveness of Power Plant Emissions Control Technologies, June 2007.

32. *See* Enclosure 11. August 18, 2005 Application to Permit to Construct – South Heart Power Project, page 4-16 and June 2006 Gascoyne 500 Generating Station and Gascoyne Mine Application For A Permit To Construct And Air Quality Technical Analysis.

33. Although NDDH rejected TESCR for these projects due to high cost effectiveness, these examples illustrate how exceptionally high the B&McD estimates are for capital costs.

34. *See* Enclosure 12. WE Energies submitted information to the Public Service Commission (PUC) of Wisconsin indicating that the cost of its SCR system was higher than the costs identified in this study. Even if the costs from the PUC submittal are used to calculate the cost per kW, however, these costs are significantly below Minnkota's estimated capital costs.

PSE&G also retrofitted its Mercer Units 1 and 2 with cold-side SCRs. The capital cost for these retrofits was about $120 million.[35] This comes out to approximately $185/kW. Although EPA and NDDH asked Minnkota to conduct a general comparison of the capital costs of installing SCR at MRYS with the costs of LDSCR at these units, Minnkota declined to conduct this comparison.

Minnkota has not explained the fact that the estimated capital costs for LDSCR and TESCR at MRYS are so much higher than any other SCR system built, including the LDSCR systems for Oak Creek and Mercer Stations. B&McD implies that the unique nature of the application of SCR at MRYS creates a situation where seemingly no comparison to another SCR installation is appropriate. As noted above, even if an SCR installation at MRYS would provide unique challenges because of the different fuel or boiler type, this would not result in capital costs that are over one and a half times as high as the upper end of SCR installations with the highest degree of retrofit difficulty. The differences for the basic capital cost equipment at MRYS would not be expected to differ from other SCR installations on the scale estimated by B&McD and no reasonable explanation has been provided by Minnkota for the large disparity. As such, close examination of the stated costs must be conducted by NDDH to justify the cost-effectiveness in its BACT determination.

EPA has examined these costs based on the information available during the public notice period and believes that the B&McD analysis that NDDH relied upon included redundant costs, insufficient justification for some of the cost estimates, and many components in the cost methodology used to calculate Total Capital Investment that are unauthorized, inappropriate, and inconsistent with the Control Cost Manual or other EPA-approved methods. When these items are taken into account, it is clear that the cost values submitted by Minnkota and adopted into the Draft BACT Determination result in a calculation of cost effectiveness that is grossly inflated and ill-suited for comparisons with other BACT determinations.

First, as explained in detail in Mr. Hans Hartenstein's April 2010 expert report[36], many of the assumptions and design parameters that B&McD specified to SCR system and catalyst vendors resulted in excessive equipment components and sizing of the SCR system and the auxiliary/ balance of plant components, which drove up materials and labor costs. If the system was designed to minimize capital costs, the general design would be different and the cost of materials and labor would be much less. Furthermore, there appears to be redundancy for some items that were included as "SCR System Equipment" and "Auxiliaries/Balance of Plant" costs.

35. *See* PSG&E press release at: http://www.pseg.com/media_center/pressreleases/articles/2006/2006-11-30.jsp. EPA verified the capital costs with communications with the New Jersey Department of Environmental Protection and Mr. Hans Hartenstein.

36. *See* Enclosure 13. Portions of this enclosure are subject to a confidential business information claim and will be submitted separately and noted as CBI.

For example, the "Auxiliaries/Balance of Plant" costs include "SCR bypass ducts and isolation dampers." The SCR system vendor that provided a pricing proposal, which appears to have been directly used by B&McD for the "SCR System Equipment" cost, included an SCR system with "gas bypass for maintenance." Although vendor information can be used instead of the capital cost equations detailed in the Control Cost Manual, Minnkota has not provided a basis for the "Auxiliaries/Balance of Plant" costs, which are 80% of the "SCR System Equipment" costs. Perry's Chemical Engineering Handbook, 6th Edition (Table B2) uses factors related to total equipment costs which would be similar to the "SCR System Equipment" used in the B&McD analysis. Perry's adds 55% to equipment costs for auxiliaries compared to B&McD's 80%. The redundancies and comparatively high costs used for "Auxiliaries/Balance of Plant" that NDDH relied upon in the Draft BACT Determination are unreasonable and not supported by the record without further justification.

Another major concern is the degree to which the B&McD capital cost analysis deviates from the Control Cost Manual methodology and includes numerous indirect cost and other accounting mechanisms that are not included in the Control Cost Manual and not adequately justified. Minnkota's February 11, 2010 submittal claims that, "Burns & McDonnell used standard estimating practices to estimate direct, installation, and indirect capital costs for MRYS Unit 1's and Unit 2's hypothetical application of low-dust and tail end technologies." While these estimating practices may be standard for use by B&McD or the utility industry for internal justification or other accounting purposes, they are not appropriate for use in the context of the BACT analysis. The standard approach is outlined in the Control Cost Manual, so that comparisons of cost-effectiveness can be made with other projects nationally. B&McD's approach undermines the ability to make these comparisons.[37]

For example, B&McD calculated total indirect capital costs that equal about 50% of the total direct capital cost compared to the Control Cost Manual which uses 20%. Of this 50%, approximately 15% is listed as a "scope contingency" and another 15% is listed as a "pricing contingency." The Control Cost Manual includes two contingencies for SCRs. The first is a "process contingency" that is calculated as 5% of the <u>direct</u> capital costs. The second is a 15% "project contingency" and is not considered to be part of the indirect capital costs. B&McD indicates that its "pricing contingency" is equivalent to the "project contingency" in the Control Cost Manual. B&McD's "pricing contingency" will actually be somewhat lower than the Control Cost Manual's "project contingency" because, unlike the "project contingency" of the Control Cost Manual, the 15% is not applied to the indirect capital costs. The "project contingency" of the Control Cost Manual is calculated as 15% of the total direct <u>plus</u> indirect

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37 Enclosure 14 is an example of a cost analysis submitted to NDDH as part of a BART submittal that does not include many of the indirect capital costs and contingencies included in B&McD's analysis. Although EPA may not be in agreement with every aspect of the cost analysis in the example, it does illustrate a case where the Control Cost Manual format is generally followed and the estimated capital costs are far less (by a factor of almost 4 for LDSCR on Unit 2, which is a smaller unit in comparison to the example and should cost less) than what was estimated for MRYS.

capital costs. However, B&McD's "scope contingency" of 15% is significantly higher than the Control Cost Manual's 5% "process contingency." Assuming, as B&McD did, that the "project contingency" is part of the indirect capital costs, it would equal 18% of the direct capital costs and the total indirect capital costs for the Control Cost Manual would equal 38% of the direct capital cost compared to 50% of the capital costs in the B&McD.[38] There are other discrepancies between B&McD's indirect costs and those in the Control Cost Manual. These differences are tabulated below.

Table 1. Comparison of Control Cost Manual & B&McD Indirect Capital Costs[39]

Indirect Capital Costs	Control Cost Manual (% of Direct Cap Cost "A")	B&McD Analysis (% of Direct Cap Cost "A")	Comparison
General Facilities (Construction Mgt)	0.05 *X* A	0.04 *X* A	B&McD 1% Lower
Engineering & Home Office Fees	0.10 *X* A	0.15 *X* A	B&McD 5% Higher
Startup Expenses	0	0.02 *X* A	B&McD 2% Higher
Process Contingency (Scope Contingency)	0.05 *X* A	0.15 *X* A	B&McD 10% Higher
Project Contingency (Pricing Contingency)	0.18 *X* A	0.15 *X* A	B&McD 3% Lower
Totals	**0.38 X A**	**0.51 X A**	**B&McD 13% Higher**

While this difference of 13% is significant, B&McD then adds two more contingencies ("cost escalation during project" and "owner's costs – other") and includes an allowance for funds during construction (interest) before calculating the total capital investment. The Control Cost Manual allows for "preproduction costs" of 2% of the total direct, indirect capital costs, and the "project contingency." Table 2 below compares these "other" costs used by B&McD and the preproduction costs in the Control Cost Manual. To normalize these costs with those tabulated above, percentages were converted back to the direct capital costs ("A").[40]

38. Per the Control Cost Manual, indirect capital costs = 0.2 times the direct capital costs. So, 15% of the total of direct capital costs plus indirect capital costs = (1.2 * direct capital costs) (0.15) = 18% of direct capital costs.
39. Although, B&McD stated in their December 11, 2010 submittal that their BACT cost estimates "follow the outline of Table 2.5 in the SCR Chapter of EPA's Control Cost Manual," many items do not match in description, so some assumptions had to be made. Where there are differences, the B&McD cost is in parentheses. Also, as noted above, this comparison assumes that "project contingency" of 15% is part of the indirect costs, so when applied exclusively to the direct capital costs only, it becomes 18%.
40. Preproduction costs are listed as being 2% of the total direct (A), indirect (B), and "project contingency" (C) costs. This becomes 3% of the total direct capital costs. (B = 0.20 * A; C = 0.18 * A; A + B + C = 1.38 A; 0.02 * 1.38 A = 0.03).

Table 2. Comparison of EPA Control Cost Manual & B&McD "Other" Capital Costs

Other Costs	Control Cost Manual (% of Direct Cap Cost "A")	B&McD Analysis (% of Direct Cap Cost "A")	Comparison
Cost Escalation	0	0.30 *X* A	B&McD 30% Higher
Allowance for Funds During Construction (Interest During Construction)	0	0.20 *X* A	B&McD 20% Higher
Preproduction Costs	0.03A	0	B&McD 3% Lower
Owners Cost – Other (Owner Contingency)	0	0.17 *X* A	B&McD 17% Higher
Totals	**0.03 X A**	**0.67 X A**	**B&McD 64% Higher**

Based on Tables 1 & 2 above, the B&McD cost analysis methodology results in capital costs that are higher by a factor of about 1.8 (0.13 + 0.64 higher) than what would be calculated using the Control Cost Manual, assuming the same base costs for total direct capital costs. As noted above, the total direct capital costs used by B&McD appears to be overestimated. A large portion of this discrepancy comes from the "other" costs added by B&McD (Table 2) that are not included in the Control Cost Manual. These appear to be strictly contingencies and accounting items which would not be at all unique to MYRS and, therefore, are not justified in the analysis. These accounting items are unauthorized under the Control Cost Manual, create an unlevel playing field for comparison with other BACT analyses and alone account for an increase in capital costs from the Control Cost Manual by a factor of 1.6.

Although NDDH asked B&McD to provide a detailed explanation regarding its high indirect capital cost estimates, B&McD's February 11, 2010, response to this request fails to justify why the B&McD cost methodology should be allowed for the MRYS BACT analysis, when it is not part of the Control Cost Manual and is not the standardized methodology used by other sources. While the Control Cost Manual does contemplate some flexibility in some contingencies (such as degree of retrofit difficulty), B&McD has not substantiated the need to go beyond standard contingencies applied through the Control Cost Manual. As stated in the Control Cost Manual, "[c]ontingencies is a catch-all category that covers unforeseen costs that may arise, such as possible redesign and modification of equipment, escalation increases in cost of equipment, increase in field labor costs, and delays encountered in start-up."41 Thus, the contingency in the Control Cost Manual should already account for possible changes in labor costs, and inclusion of a contingency plus escalation of costs is redundant according to the Cost Manual Methodology. Escalation of costs should not be included as a separate estimate in the estimate of Total Capital Investment since it is included as part of the contingency estimate. In Table 2.5 of the SCR chapter of the Control Cost Manual, the "Allowance for Funds During

41. *See* Control Cost Manual, 2002, Chapter 2, Section 2.3.1.

Construction" (inflation) is specifically listed as zero. It is unclear then why B&McD added what amounts to 20% of the direct capital costs to cover inflation. Including "owner's costs" and "owner's contingency" is also not consistent with the Cost Manual Methodology and appears to be redundant.

B&McD mentions that it is anticipated that significant retrofit work will be required which will affect the scope and price of the project. However, there have been many SCR retrofits facing much more difficult challenges with space limitations and boiler modifications than MRYS can be expected to face installing a LDSCR or TESCR downstream of the ESP (or FGD) in a rural location. The contingencies outlined in the Control Cost Manual (5% process contingency and 15% project contingency) are sufficient for purposes of the BACT analysis.

B. <u>Inflated Annual Cost Estimations & Cost Methods</u>

In addition to the inflated capital cost estimates and inappropriate cost methods used by B&McD in the MRYS BACT analysis that NDDH relied upon, B&McD also used inflated and unjustified cost estimates for annual costs and used costing methods that are unauthorized by the Control Cost Manual. Below are some of the issues identified by EPA. These are listed following the numbering scheme in the detailed itemized B&McD BACT cost analysis submitted December 11, 2009 and updated February 11, 2010.

(1) Annual Maintenance Costs:

B&McD uses a factor of 3% of the installed capital costs of the SCR equipment and auxiliary equipment. The Control Cost Manual uses a factor of 1.5% of total capital investment. No justification was given by B&McD for using a cost factor that is twice as high.

(2) Annual Reagent Costs:

As stated in NDDH's January 11, 2010, letter to Minnkota and in Mr. Hartenstein's expert report, the choice to use urea instead of anhydrous ammonia drives up annual costs. As also stated in Mr. Hartenstein's expert report, the reasons given by B&McD in the February 11, 2010, response to NDDH are not unique to MRYS and do not constitute justification for choosing the more expensive reagent. Since excessive cost is the main reason cited by NDDH for not selecting the top level of control as BACT and there is a less expensive option that is available, the analysis should be redone using anhydrous ammonia.

(3) Annual Electricity Costs:

In its February 11, 2010, response to NDDH, B&McD provided an explanation of the electricity costs associated with extended outage periods for catalyst replacements and ASOFA maintenance.[42] In its analysis, B&McD estimates the following times for various stages of catalyst replacement:

1) Reactor Cool Down:	48-60 hours
2) Installation into spare catalyst layer:	128 hours (16 shifts - one time event)
3) Removal of spent catalyst and installation of fresh catalyst:	192 hours (24 shifts)
4) Reactor heating for startup:	36-48 hours
Total (Items 1, 2 & 4):	276-300 hours

Conservatively assuming that one spent catalyst is always removed when a fresh catalyst is added and disregarding the unreasonable assumption that only two shifts per day would be used to perform the work while the unit remains idle, the range of total outage time estimated by B&McD to cool down the reactor, exchange catalyst, and reheat the reactor is 276 – 300 hours, or 11.5 – 12.5 days. This does not include the 96 hours (or four days) of regular scheduled boiler cleaning downtime that should be subtracted from these totals. **When this is accounted for, there would be a maximum of 204 hours for each catalyst exchange in excess of normal downtime for each unit.**

Even under B&McD's unwarranted "Scenario B" assumption that catalyst is replaced three times per year for Unit 1 and four times per year for Unit 2, this equates to a maximum of 900 hours per year of catalyst replacement time for Unit 1 and 1,200 hours per year for Unit 2. This does not include the 96 hours (or four days) of regular downtime that should be subtracted from these totals for each outage period. **When this is accounted for, there would be a maximum of 612 (900 – 288) hours per year for Unit 1 and 816 (1,200- 384) hours per year for Unit 2 under B&McD's worst case scenario.**

B&McD states that the excess downtime for SCR catalyst replacements under "Scenario A" would be 213 and 256 hours for Unit 1 TESCR and LDSCR respectively, and 206 and 247 hours for Unit 2 TESCR and LDSCR respectively. It is unclear how B&McD came up with these values considering they are higher than the high end total of what was outlined for each stage of the catalyst replacement once subtraction was made for normal boiler cleaning (maximum of 204 hours).

42. The NSR Workshop Manual states: "Lost production costs are not included in the cost estimate for a new or modified source." Appendix B, p.11. For the purpose of this analysis, EPA is assuming lost production is included in the cost estimate.

Furthermore, B&McD states that the excess downtime for SCR catalyst replacements under "Scenario B" would be 980 and 938 hours for Unit 1 LDSCR and TESCR respectively, and 1,234 hours for Unit 2 (LDSCR and TESCR). Again, it is unclear how B&McD came up with these values considering they are higher than the high end total of what was outlined for each stage of the catalyst replacement, even if no time of the outage was subtracted for normal boiler cleaning (900 hours for Unit 1 and 1,200 hours for Unit 2). When the subtraction for normal boiler cleaning is made, there is an even larger discrepancy between B&McD's estimations and what was outlined for each stage of the catalyst replacement (612 hours for Unit 1 and 816 hours for Unit 2).

While B&McD's additional outage times do not appear to correspond to the sum of the catalyst replacement steps outlined in their February 11, 2010, submittal, they also do not appear to reflect the information they received from SCR system and catalyst vendors and their consultants. The information received from these sources is addressed below.

Reactor Cool Down: Based on a September 29, 2010, email from Babcock & Wilcox Construction Co. Inc., Minnkota was advised that "we typically see 36 to 48 hrs before entering the SCR." It is unclear why B&McD used 48-60 hours (although, as noted above, even using the high end of their range, the additional outage times stated by B&McD seem to exceed what would be calculated.) **EPA believes 48 hours for reactor cool down would be a conservative estimate.**

Catalyst Exchange: According to a September 15, 2009, email, B&McD's consultant Fuel Tech's, "'rule of thumb' estimate for catalyst installation is thirty (30) minutes per module." This is based on conventional access, use of hoists for module handling and transport, and a typical crew of 4 to 6 people. With different system design and more personnel, the time period can certainly be reduced."

As stated in Mr. Hartenstein's expert report, "[b]ased on the catalyst designs from HTI and CERAM submitted to Minnkota, the number of modules per layer ranges from 96 – 104 for Unit 1 and 162 – 182 for Unit 2. Using the stated conservative 'rule of thumb' estimate of thirty minutes per module, this equates to maximum time of 2.2 days for Unit 1 and 3.8 days for Unit 2 to replace a layer of catalyst. As stated by Fuel Tech, this 'rule of thumb' estimate could be further reduced through design and personnel." This equals a maximum of 52 hours for Unit 1 and 91 hours for Unit 2.

Based on B&McD's February 11, 2010, submittal the difference in time between removing spent catalyst (16 shifts) and the removal of spent catalyst and installing fresh catalyst (24 shifts) is 64 hours.

So, the maximum total time for removing a layer of spent catalyst and installing fresh catalyst is as follows:

Unit 1: 64 hours + 52 hours = 116 hours
Unit 2: 64 hours + 91 hours = 155 hours

These are both lower than the time described in the February 11, 2010, response for removing spent catalyst and installing fresh catalyst (192 hours) Again, even using the apparently inflated value of 192 hours, the additional outage times stated by B&McD seem to exceed what would be calculated using these values.

Reactor Preheating for Startup: B&McD has stated this will take 36-48 hours. Based on the very conservative nature of their other estimates and the comments in Mr. Hartenstein's expert report on this subject, **EPA believes 36 hours for reactor preheating would be a conservative estimate.**

Using the information supplied to B&McD and Minnkota from SCR system and catalyst vendors, and B&McD's consultants, EPA calculates that a conservative total estimate of excess downtime (subtracting the four days for normal cleaning downtime) from bringing the unit down, to replacing spent catalyst with fresh catalyst, to bringing the SCR back online for one layer of catalyst exchange is as follows:

Table 3. EPA Estimates for Catalyst Exchange Times

Replacement Step	**Time Unit 1 (hours)**	**Time Unit 2 (hours)**
Reactor Cool Down	48	48
Spent Catalyst Removal and Installing Fresh Layer	116	155
Reactor Preheating for Startup	36	36
Subtract Scheduled Downtime	-96	-96
EPA Total Estimate	104	143
B&McD Estimate (Scenario A)	213-247	206-247
Difference	**109-143**	**63-104**

As can be seen from Table 3 above, B&McD's estimates for catalyst exchange times are over twice as high for Unit 1 and over 50% higher for Unit 2 when compared to EPA's estimates (which were based directly on the information provided to Minnkota and B&McD by vendors and consultants).

Furthermore, B&McD added an additional 181-188 hours per year to the annual electricity costs for extra downtime due to advanced separated overfire air (ASOFA) maintenance. Even assuming these values are realistic and necessary, which should be justified by Minnkota, since the more realistic EPA estimates for catalyst exchanges for both Unit 1 and Unit 2 are less than the stated ASOFA maintenance times, it should be assumed that the SCR maintenance would be performed at least partially within the same time allotted for ASOFA-related maintenance. B&McD gives no explanation as to why the outage times for ASOFA and SCR are cumulative and the work could not be scheduled and conducted concurrently. One possible reason would be if there were short interruptions required for ASOFA maintenance that did not correspond with the normal unit cleanings. This seems unlikely (especially for 181 – 188 hours per year) and B&McD has not indicated that this would be the case normally. Appendix C3 of the original 2006 NO_x BACT Analysis provides the only basis that EPA can find for including any ASOFA downtime. Page C3-3 describes lost availability due to "forced or extended scheduled boiler outages that may result from problematic cyclone slag tapping operational conditions encountered during substoichiometric cyclone operation with SOFA." These times should be justified, as well as the need to conduct this maintenance at a different time from the normal boiler cleanings and/or the SCR catalyst replacements. If it is found that ASOFA maintenance times can fall within the same normal boiler cleaning outages, B&McD's cost estimate must subtract all electricity costs attributed to extended outage times for catalyst replacements accordingly.

Finally, it appears that for "Scenario A", B&McD did not take into account that the catalyst exchanges will not be occurring each year. Since they will be occurring approximately every other year, these costs need to be adjusted to an annual basis.

(4) Annual Water Costs:

No comments.

(5) Catalyst Replacement Costs:

Based on Note 5 in the detailed itemized B&McD BACT cost analysis submitted December 11, 2010, and updated February 11, 2010, B&McD assumed a catalyst price of $7,500 per cubic meter (in 2006 dollars) in calculating annual catalyst replacement costs. This assumption appears to be significantly higher than either of the bids the two catalyst vendors provided to Minnkota. Furthermore, this value is also substantially higher than two of the three vendor bids received by Mr. Hartenstein's in response to his vendor inquiry. It is unclear why B&McD used a unit catalyst price higher than any vendor bid they received for their BACT analysis. While a higher unit price may be justifiable for TESCR compared to LDSCR, it appears from Note 5 that B&McD used the same price for LDSCR and TESCR. Sufficient detail is not provided on how adjustments were made for the different volumes required for each catalyst replacement in a LDSCR and TESCR application.

Furthermore, B&McD did not seem to consider the use of regenerated catalyst in pricing catalyst replacements. Catalyst regeneration has been in practice in the utility industry for years to help save SCR maintenance costs and typically costs less than half of what new catalyst would cost. If there is some reason Minnkota cannot use regenerated catalyst at MRYS, this should be justified.

(6) Natural Gas for Flue Gas Reheating & Urea Conversion System:

As noted above and in Mr. Hartenstein's expert report, EPA questions whether natural gas needs to be used instead of steam to reheat flue gas and whether urea needs to be used instead of anhydrous ammonia at MRYS. See Mr. Hartenstein's expert report for more information.

(7) Operating Labor for SCR:

EPA agrees that no operating labor (or supervisory labor) should be included, consistent with the Control Cost Manual.

(8) Annual Costs for Capital Recovery:

Based on greatly inflated capital costs (addressed extensively above), the annual capital recovery cost is likewise greatly inflated.

(9) Administrative Overhead, Insurance, Taxes, etc.:

No comments.

In addition to the above comments, the levelized total annualized cost approach used by B&McD is inappropriate, as it is inconsistent with the Control Cost Manual. Based on Note 15 in the detailed itemized B&McD BACT cost analysis submitted December 11, 2010, and updated February 11, 2010, B&McD increased the total direct annual costs (all annual costs with the exception of capital recovery) by a factor of 1.25. While these estimating practices may be standard for use by B&McD or the utility industry for internal justification or other accounting purposes, they are not appropriate for use in the context of the BACT analysis. The standard approach is outlined in the Control Cost Manual, so that comparisons of cost-effectiveness can be made with other projects nationally. B&McD's approach undermines the ability to make these comparisons.

The Control Cost Manual methodology provides estimates of operation and maintenance that do not change with interest rate and equipment life. The equivalent uniform annual cost estimates from the Control Cost Manual are equal across the life of the equipment. Changing the interest rate and equipment life will change the annualized capital cost estimate, but should not change the annual operation and maintenance costs. The Control Cost Manual procedure provides real estimates of costs (that is, inflation-adjusted), and not nominal costs.

C. EPA Corrected Cost Analysis

Due to the inflated nature of B&McD's cost estimates, EPA conducted an independent cost analysis for LDSCR and TESCR at MRYS. This analysis consisted of two parts. The first was to request budgetary proposals from several catalyst vendors on catalyst performance guarantees (NO_X removal, initial catalyst life, and ammonia slip), catalyst volume and dimensions, catalyst exchange diagrams up to approximately 100,000 hours, and catalyst price. The Request for Proposal (RFP) was based on what EPA believes to be representative flue gas characteristics and design specifications for a LDSCR on Unit 1 and a TESCR on Unit 2. Mr. Hartenstein was hired by the Department of Justice to perform this work on behalf of EPA.

The RFP was sent to three catalyst vendors (CERAM, Johnson Matthey Catalysts (JMC), and Haldor Topsoe) on March 3, 2010. While the facility in the RFP was not identified as MRYS, the flue gas characteristics in the RFP were based on relevant actual flue gas parameters found at MRYS, including recent stack test information for Unit 1 and Unit 2 and the 1983 Markowski data on particulate matter concentrations and compositions data for Unit 2. Furthermore, it was clearly stated in the RFP that the majority of the sulfates within the particulate matter are expected to be sodium and potassium sulfates. Upon request from two catalyst vendors (CERAM and JMC), a typical coal composition of Center lignite was provided. Responses from all three vendors were received between March 12 and March 31, 2010. As noted in Mr. Hartenstein's expert report, all three catalyst vendors were able to provide an initial catalyst life guarantee of 24,000 operating hours in response to the RFP, as well as providing catalyst size and price specifications at the guaranteed NO_X and ammonia slip rates. More detail is provided in Mr. Hartenstein's expert report. The RFP and the vendor responses are also attached.[43]

The second part of the EPA's independent cost analysis was to calculate SCR cost effectiveness (dollars per ton) based on the Control Cost Manual or other appropriate methods using the relevant cost information obtained from the vendor survey conducted by Mr. Hartenstein in combination with appropriate information in the B&McD cost analysis. For this effort, EPA hired ERG as consultants.

43. *See* Enclosure 15. Request for Proposal and Vendor Responses. Portions of this enclosure are subject to a confidential business information claim and will be submitted separately and noted as CBI.

ERG first evaluated the cost factors and methodology used by Minnkota and made a comparison with the cost factors and methodology used in the Control Cost Manual. To cross check the Control Cost Manual results, ERG also compared cost factors and methodology used by Minnkota to those used in Perry's Chemical Engineering Handbook 6th Edition (Perry's). To make these comparisons, ERG used the capital and annual cost tables for shared facilities in Minnkota's December 11, 2009, submittal. For the capital costs, ERG back-calculated the cost factors B&McD used to escalate SCR equipment costs to a final capital cost number. This calculation showed that for the B&McD analysis:

- The cost for auxiliaries/balance of plant is approximately 80% of the SCR costs.
- Capital constructions costs are approximately 50% of capital equipment costs (SCR plus auxiliaries).
- Indirect capital costs are approximately 50% of total capital costs.
- B&McD added another 47% to the capital plus indirect total to account for cost escalation, interest, and owner's costs.

ERG then compared these cost factors with percentages used in the Control Cost Manual, as well as Perry's. The comparison of total capital costs calculated by B&McD and the Control Cost Manual is described in detail above under the capital cost analysis. Perry's uses costs factors that are applied to total equipment costs. These total equipment costs would be considered equivalent to the SCR system cost used by B&McD's methodology. Comparing the B&McD and Perry's cost factors shows:

- Perry's adds 55% to equipment costs for auxiliaries compared to B&McD's value of approximately 80%.
- Total direct costs in Perry's are 2.3 times the SCR system costs while the B&McD total direct costs are about 2.7 times the SCR costs.
- For the indirect line items included in B&McD's cost table, Perry's adds 56% to the direct costs which is similar to Minnkota's value of approximately 50%.
- Perry's does not include the factors B&McD added to the capital plus indirect to account for cost escalation, interest, and owner's costs.

Because B&McD's cost factors are higher than both the Control Cost Manual and Perry's factors, EPA calculated two additional capital cost cases for comparison. Both cases used the same format as in B&McD's estimate, but used the Control Cost Manual and Perry's cost factors, where available. ERG used the 2009 B&McD's SCR costs which were back-calculated from the 2018 costs provided by Minnkota.[44] As can be seen from Table 4 and Figure 1, the capital costs estimated by B&McD for Minnkota are much higher than both the Control Cost Manual and Perry's. The Control Cost Manual and Perry's methods compare favorably.

44. EPA strongly disagrees with B&McD assumption that the SCR in this matter will not be installed until 2018.

Table 4. Capital Cost Comparison				
Capital Costs (2009, 1,000$)	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**
Minnkota	$146,753	$254,175	$192,830	$329,150
OAQPS	$91,114	$162,999	$120,629	$212,529
Perry's	$87,613	$147,699	$108,416	$196,954

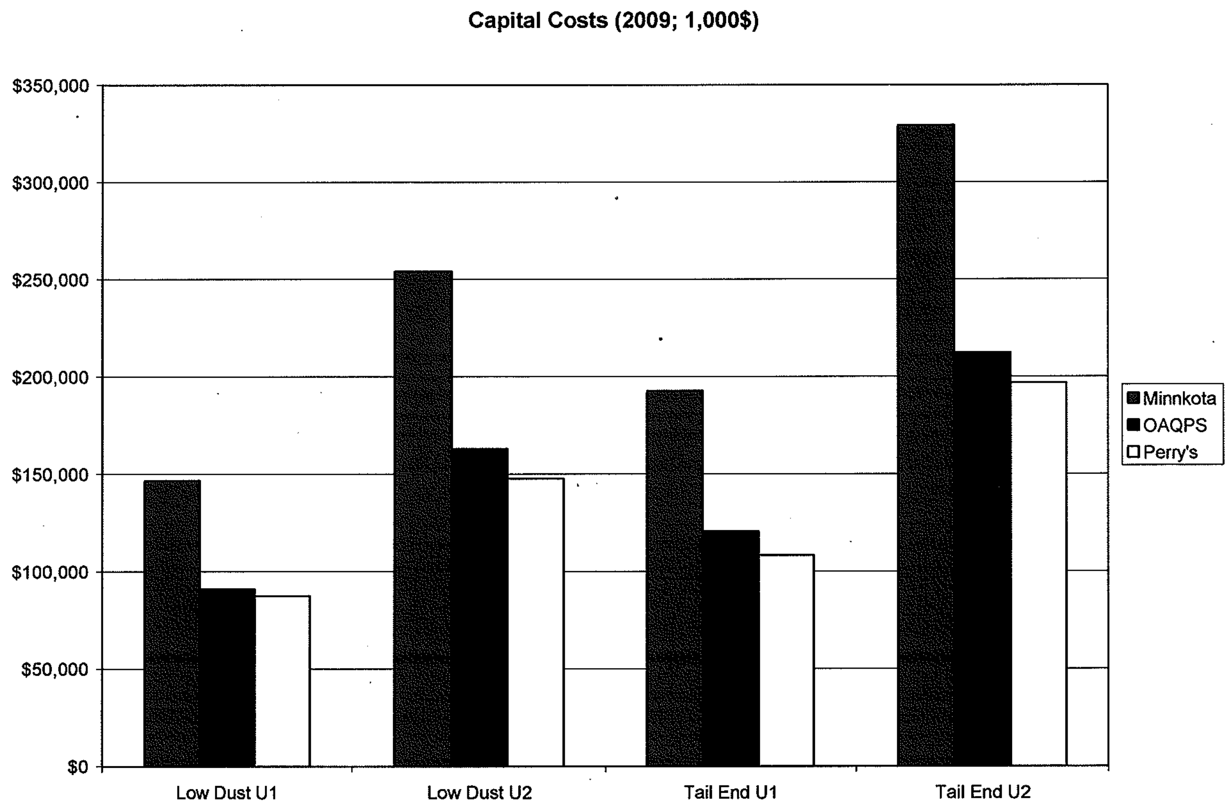

Figure 1: Comparison of Capital Costs Using Different Cost Methods

ERG then performed a new cost analysis that calculated capital and annual costs using the Control Cost Manual methodology and factors where applicable along with B&McD's original SCR equipment costs and other cost data that could not be independently verified by EPA within the time allowed (auxiliaries/balance of plant, construction costs, natural gas pipeline, reagent costs, natural gas costs), supplemented with other cost data and assumptions provided by EPA. While EPA could not independently verify many of these costs, they were included to produce an estimate that may overestimate actual costs, but is conservative in a manner favorable to Minnkota. EPA provided ERG with different information regarding catalyst volume, catalyst cost, catalyst replacement frequency, and estimated additional outage time for replacing spent catalyst. A conservative value for catalyst cost of $6,000 per cubic meter was used. As noted above, this cost could be significantly reduced if regenerated catalyst was used. Contingencies were calculated using the Control Cost Manual assumptions. The maintenance costs were adjusted using the cost factor in the Control Cost Manual and annual costs were not "levelized" as done in the B&McD analysis.

ERG used the above information and calculated annual costs. ERG calculated four different catalyst replacement scenarios. Scenarios 1 through 3 assume catalyst replacement of one layer per year, one layer every two years, and one layer every three years. EPA believes Scenario 3 is the most appropriate, as it reflects the performance guarantees provided by three catalyst vendors in response to Mr. Hartenstein's RFP and the proposals provided to Minnkota by one vendor. No calculations were made for the "Scenario B" assumptions used by B&McD because, as EPA has stated previously and is well-documented in Mr. Hartenstein's expert report, these assumptions are unsubstantiated and arbitrary. ERG's Scenarios 1-3 do not include downtime for ASOFA because this has not been justified by Minnkota. Scenario 4 was run as the "worst-case" scenario and assumes all of the additional outage time is based on the additional outage times estimated for ASOFA provided by B&McD. There would be no additional unit outage time (and associated electricity costs) for catalyst replacement, because all of this work could be completed within the time allocated for ASOFA maintenance. As noted above, EPA does not necessarily concur that these additional outage times for ASOFA are legitimate and believes they should be justified by Minnkota. ERG modified the amount of time required for each catalyst layer replacement from B&McD's assumptions, recalculated the unit availability using the revised downtime, and recalculated electricity costs and corresponding NO_X emissions using the new availability. Table 5 shows the costs for each scenario. The annual costs in this table include the annual costs associated with capital recovery.

Table 5. Annual Cost Comparison

Annual Costs (2009, 1,000$)	Low Dust U1	Low Dust U2	Tail End U1	Tail End U2
Minnkota - Scenario A	$36,923	$63,162	$43,290	$73,245
Minnkota - Scenario B	$49,829	$95,310	$56,098	$106,022
OAQPS - Scenario 1	$19,753	$34,114	$23,016	$39,345
OAQPS - Scenario 2	$18,714	$30,837	$21,768	$36,464
OAQPS - Scenario 3	$18,081	$30,524	$21,660	$36,287
OAQPS - Scenario 4	$20,449	$33,370	$23,708	$38,598

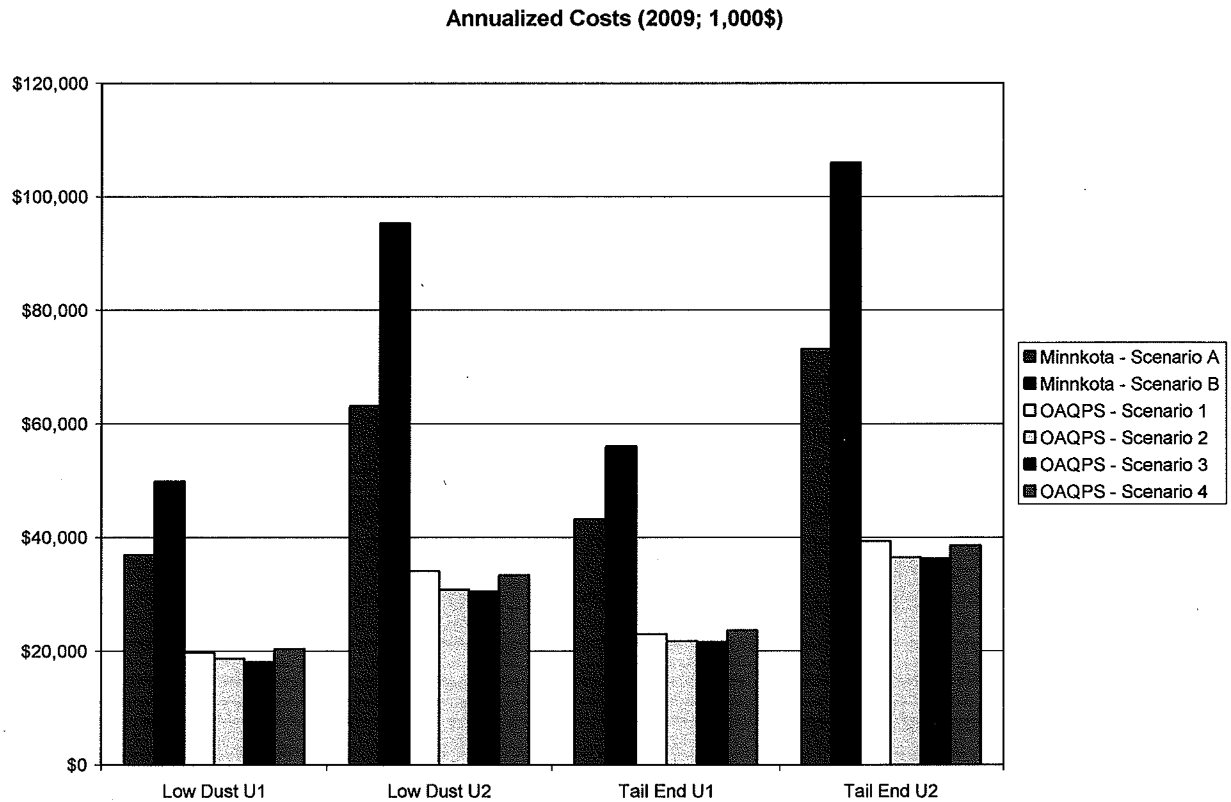

Figure 2: Comparison of Annual Costs Using Different Cost Methods

Table 6 shows the costs in dollars per ton of NO_X removed in both 2009 and 2006 dollars. North Dakota averaged B&McD's Scenario A and B in their summary, which is also shown on the table. As can be seen from the table, when the Control Cost Manual cost factors are used in conjunction with baseline cost information provided by B&McD, supplemented with more reasonable cost data and assumptions on certain cost data, the cost-effectiveness is less than half of the "average" value of the two B&McD scenarios used by NDDH, even under the assumption that a layer of catalyst is replaced is every year (Control Cost Manual Scenario 1). This assumption is three times higher than the catalyst exchange rate that was provided in proposals from one catalyst vendor to Minnkota and performance guarantees provided to Mr. Hartenstein from three catalyst vendors. ERG's analysis is attached.[45]

45. *See* Enclosure 16.

Table 6. Cost Comparison Dollar per Ton Removed				
2009 Dollars (1,000$)				
Annual Costs	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**
Minnkota - Scenario A	$3,950	$4,250	$4,632	$4,930
Minnkota - Scenario B	$5,300	$6,362	$5,969	$7,078
North Dakota	$4,625	$5,306	$5,301	$6,004
OAQPS - Scenario 1	$2,120	$2,301	$2,464	$2,654
OAQPS - Scenario 2	$2,010	$2,081	$2,332	$2,461
OAQPS - Scenario 3	$1,942	$2,061	$2,321	$2,451
OAQPS - Scenario 4	$2,194	$2,188	$2,537	$2,531
2006 Dollars (1,000$)				
Minnkota - Scenario A	$3,586	$3,859	$4,206	$4,476
Minnkota - Scenario B	$4,813	$5,777	$5,420	$6,426
North Dakota	$4,200	$4,818	$4,813	$5,451
OAQPS - Scenario 1	$1,925	$2,089	$2,238	$2,410
OAQPS - Scenario 2	$1,825	$1,890	$2,117	$2,235
OAQPS - Scenario 3	$1,764	$1,872	$2,108	$2,225
OAQPS - Scenario 4	$1,992	$1,987	$2,304	$2,298

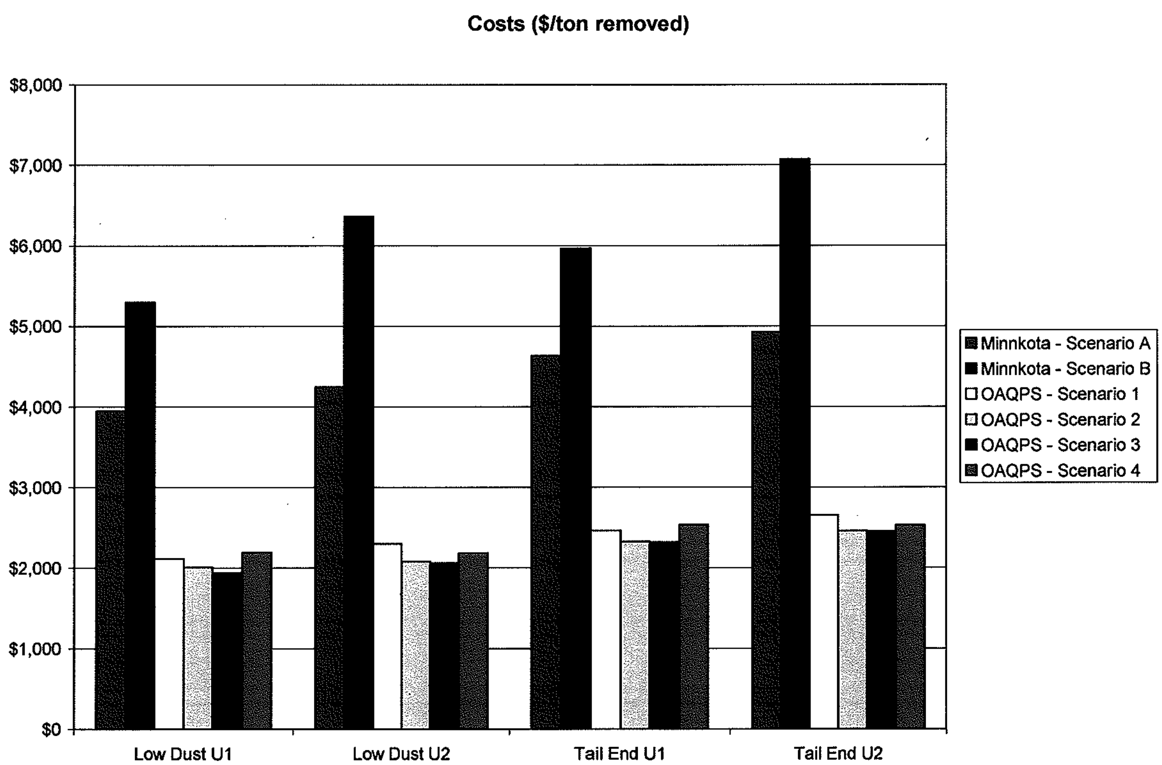

Figure 2: Comparison of Cost-Effectiveness Using Different Cost Methods

III. Conclusions

EPA requests that NDDH reconsider its preliminary BACT determination and find that SCR represents BACT controls at MRYS. Since SCR has been successfully applied worldwide to such a wide variety of sources, there is a presumption that it is both technically and economically feasible at MRYS. Minnkota failed to produce sufficient evidence to overcome this presumption. Although NDDH identified some adverse energy and environmental impacts associated with the use of SCR, it correctly concluded that these impacts would not preclude the selection of SCR as BACT.

As more fully set forth above, Minnkota's cost estimates were not conducted in accordance with the NSR Manual and the Control Cost Manual, and resulted in grossly overestimated SCR costs. NDDH relied upon Minnkota's faulty cost estimates to conclude that the cost effectiveness of LDSCR at MRYS was $4,201 per ton for Unit 1 and $4,822 per ton for Unit 2. Even these inflated and unreasonable cost estimates must result in a conclusion that LDSCR is cost effective at MRYS. It is clear that many other sources have borne costs that are more than this.

NDDH is required to base its BACT determination on cost estimates that are consistent with the NSR Manual and the Control Cost Manual. If Minnkota had followed the applicable methodology, it would have resulted in a determination that the cost effectiveness of SCR at MRYS was about $2,000 per ton. For the reasons set forth above, NDDH should reject Minnkota's cost analysis and base its BACT determination on the application of the NSR Manual and the Control Cost Manual. An objective review of these results would show that SCR is cost effective.

If you would like to discuss any of these matters, please call Cynthia Reynolds at (303) 312-62006 or Brenda Morris at (303) 312-6891.

Sincerely,

Andrew M. Gaydosh
Assistant Regional Administrator
Office of Enforcement, Compliance and
Environmental Justice

Enclosures

cc: David Glatt, NDDH (w/o Enclosures),
Dean Haas, NDDH (w/o Enclosures),
Jerry MacLaughlin, USDOJ (w/o Enclosures),
Jeff Kodish, OECA, (w/o Enclosures),
Brenda Morris, EPA (w/o Enclosures),
Hans Buenning, EPA

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MAY 2010
Received
Air Quality

May 11, 2010

Ref: 8ENF-L

Via US Mail & Email
Mr. John Cochran
CERAM Environmental, Inc.
7304 W. 130th Street, Suite 140
Overland park, Kansas 66213

Re: CERAM's Confidential Business Information (CBI) Claim Regarding Proposal No. NR090911-2

Dear Mr. Cochran:

The United States Environmental Protection Agency (EPA) has submitted its comments on the North Dakota Department of Health's (NDDH's) April 2010, Draft Best Available Control Technology (BACT) Determination for Nitrogen Oxides (NO_x) for Milton R. Young Station (MRYS), Units 1 and 2 (Draft BACT Determination). EPA's comments on NDDH's Draft BACT Determination refer to information in enclosures 13 and 15 subject to CERAM's confidential business information (CBI) claim regarding CERAM Proposal No. NR090911-2. EPA previously obtained written approval to submit the CBI to NDDH. EPA has maintained the CBI designation and transmitted that information in accordance with the federal policies regarding CBI. EPA has not reviewed this information to ascertain if it is CBI, and is not taking a position as to whether or not such a claim is valid. NDDH has a process for handling CBI which can be found at NDAC 33-15-01-16. Should EPA receive a request for this information at a later date, EPA will follow its federal CBI process.

Sincerely,

Brenda L. Morris

Brenda L. Morris, Attorney
U.S. EPA Region 8
Tel: 303-312-6891
morris.brenda@epa.go

cc: Terry O'Clair, NDDH
Jerry MacLaughlin, DOJ
Jeff Kodish, EPA, OECA
Hans Buenning, EPA, ENF-AT

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May 11, 2010

Ref: 8ENF-L

Via US Mail & Email
Wayne S. Jones
Haldor Topsoe, Inc.
17629 El Camino Real
Houston, TX 77058

Re: Haldor Topsoe's Confidential Business Information (CBI) Claim regarding Quotation No. 09-6362

Dear Mr.Jones:

The United States Environmental Protection Agency (EPA) has submitted its comments on the North Dakota Department of Health's (NDDH's) April 2010, Draft Best Available Control Technology (BACT) Determination for Nitrogen Oxides (NO_x) for Milton R. Young Station (MRYS), Units 1 and 2 (Draft BACT Determination). EPA's comments on NDDH's Draft BACT Determination refer to information in enclosures 13 and 15 subject to Haldor Topsoe's confidential business information (CBI) claim regarding Haldor Topsoe's Quotation No. 09-6362. EPA previously obtained written approval to submit the CBI to NDDH. EPA has maintained the CBI designation and transmitted that information in accordance with the federal policies regarding CBI. EPA has not reviewed this information to ascertain if it is CBI, and is not taking a position as to whether or not such a claim is valid. NDDH has a process for handling CBI which can be found at NDAC 33-15-01-16. Should EPA receive a request for this information at a later date, EPA will follow its federal CBI process.

Sincerely,
Brenda L. Morris
Brenda L. Morris, Attorney
U.S. EPA Region 8
Tel: 303-312-6891
morris.brenda@epa.go

cc: Terry O'Clair, NDDH
Jerry MacLaughlin, DOJ
Jeff Kodish, EPA, OECA
Hans Buenning, EPA, ENF-AT

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May 11, 2010

Ref: 8ENF-L

Via US Mail & Email
Ken Jeffers
Johnson Matthey Catalysts LLC
1121 Alderman Drive, Suite 204
Alpharetta, GA 30005

Re: Johnson Matthey's Confidential Business Information (CBI) Claim regarding Proposal 71779

Dear Mr. Jeffers:

The United States Environmental Protection Agency (EPA) has submitted its comments on the North Dakota Department of Health's (NDDH's) April 2010, Draft Best Available Control Technology (BACT) Determination for Nitrogen Oxides (NO_x) for Milton R. Young Station (MRYS), Units 1 and 2 (Draft BACT Determination). EPA's comments on NDDH's Draft BACT Determination refer to information in enclosures 13 and 15 subject to Johnson Matthey's confidential business information (CBI) claim regarding Johnson Matthey's Proposal No. 71779. EPA previously obtained written approval to submit the CBI to NDDH. EPA has maintained the CBI designation and transmitted that information in accordance with the federal policies regarding CBI. EPA has not reviewed this information to ascertain if it is CBI, and is not taking a position as to whether or not such a claim is valid. NDDH has a process for handling CBI which can be found at NDAC 33-15-01-16. Should EPA receive a request for this information at a later date, EPA will follow its federal CBI process.

Sincerely,
Brenda L. Morris
Brenda L. Morris, Attorney
U.S. EPA Region 8
Tel: 303-312-6891
morris.brenda@epa.go

cc: Terry O'Clair. NDDH
Jerry MacLaughlin, DOJ
Jeff Kodish, EPA, OECA
Hans Buenning, EPA, ENF-AT

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